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Pollution Control for Utility Power Generation, 1990-2020

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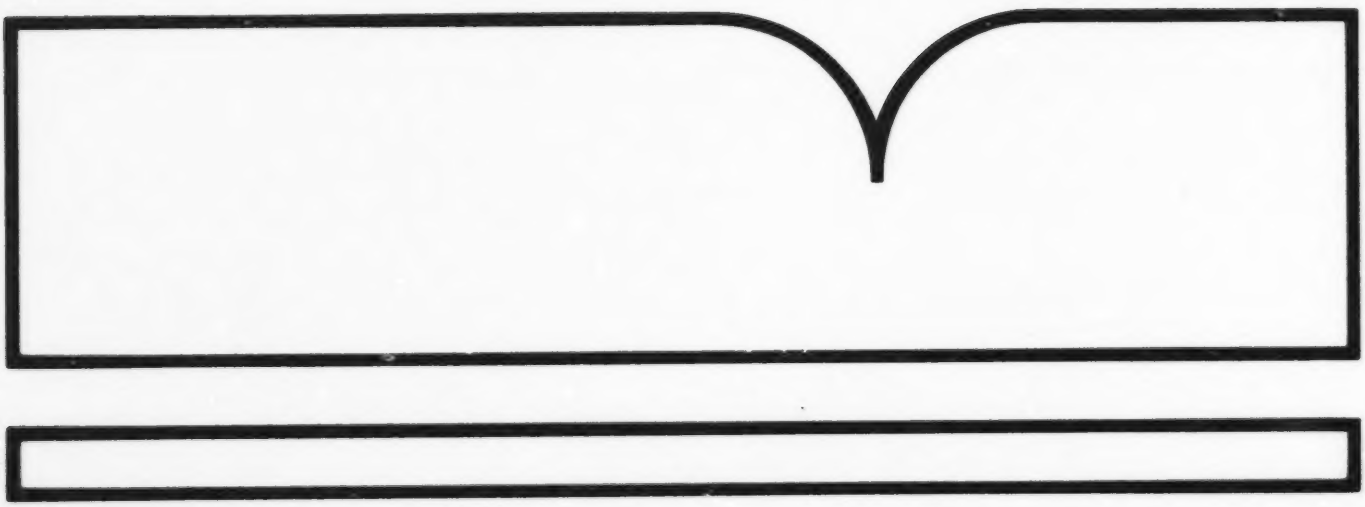

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16. ABSTRACT The paper discusses pollution control for utility power generation between the years 1990 and 2020, when the major anticipated environmental challenges facing the utility industry will be acid deposition control in the near term and global warming mitigation in the longer term. The President has proposed an ambitious acid rain control program requiring reduction of 10 million tons of sulfur dioxide (SO_2) by the year 2000. Options available to the utility industry include coal switching, flue gas desulfurization, and such emerging lower cost technologies as Limestone Injection Multistage Burners (LIMB) and Advanced Silicate (ADVACATE), both developed by EPA. Since utility boilers, especially coal boilers, are major emitters of carbon dioxide (CO_2), they are candidates for mitigation to prevent unacceptable global warming. Utility options to deal with this problem include user conservation, increased use of nuclear power, renewable generators (biomass and solar), clean coal technologies, and increased use of natural gas. Model analysis suggests that in the 1990-2020 time frame conservation is critical. Non-fossil fuel technologies can also make significant contributions to reducing CO_2 emissions, but their role is limited by likely penetration in this time frame. Clean coal technologies (e.g., integrated coal gasification combined cycle) seem to provide only marginal CO_2 reduction benefits.

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POLLUTION CONTROL FOR UTILITY POWER GENERATION, 1990 TO 2020

Frank T. Princiotta
Director
Air & Energy Engineering Research Laboratory
Office of Research & Development
U. S. Environmental Protection Agency
MD-60
Research Triangle Park
NC 27711

Abstract

The major environmental challenges facing the utility industry in the 1990-2020 time frame are acid deposition control in the near term and global warming mitigation in the longer term. The President has proposed an ambitious acid rain control program requiring reduction of 10 million tons of sulfur dioxide (SO_2) by the year 2000. Options available to the utility industry include coal switching, flue gas desulfurization, and such emerging lower cost technologies as Limestone Injection Multistage Burners (LIMB) and Advanced Silicate (ADVACATE), both developed by EPA. Since utility boilers, especially coal boilers, are major emitters of carbon dioxide (CO_2), they are candidates for mitigation to prevent unacceptable global warming. Utility options to deal with this problem include user conservation, increased use of nuclear power, renewable generators (biomass and solar), clean coal technologies, as well as increased use of natural gas. Model analysis suggests that in the 1990-2020 time frame conservation is critical. Non-fossil fuel technologies can also make significant contributions to reducing CO_2 emissions, but their role is limited by likely penetration in this time frame. Clean coal technologies (e.g., integrated coal gasification combined cycle) appear to provide only marginal CO_2 emission reduction benefits.

Introduction

The U.S. electric utility industry has shown extraordinary growth since the early part of this century. Figure 1 shows U.S. electrical production from 1930 to 1985. This figure also illustrates the dominance of coal as the major source of the derived electrical generation. Although oil and gas were significant contributors to electrical production in the 1960s and 1970s and nuclear power was a significant contributor in the 1980s, coal continues to be the dominant fuel source. Electrical use has grown from only 1 quad (10^{15}BTU) of energy utilized in the 1930s to 26 quads used in 1985. This 26 quads represents over one-third of all the energy used in the U.S. which was 74 quads in 1985.

Unfortunately, the utilization of coal involves major environmental and safety problems throughout the fuel cycle. From mine safety and strip mining's ecological damage to air pollution associated with coal combustion to the ultimate disposal of fly ash and sulfur sludge, coal use presents major challenges. Perhaps the most important of these challenges is to control gaseous emissions of important air pollutants associated with coal combustion. Table 1 describes the major regulated (criteria) and CO_2 pollutants for

which coal combustion is an important source. SO_2, nitrogen oxides (NO_x), and particulates are all currently regulated for both new and existing sources under the U.S. Clean Air Act. Of course CO_2 is unregulated but is a major contributor to potential global warming.

Table 1 also summarizes the major health and environmental concerns and the role of electrical production, particularly coal combustion, relative to other sources of pollution for each of these pollutants.

Major Environmental Challenges for the Future -- Acid Rain and Global Warming

The major environmental challenges for the electric utility industry appear to be associated with acid deposition and global warming. The acid rain challenge appears imminent in light of the near term prospect of U. S. legislation. Global warming is a longer term challenge, with the international community struggling to understand and deal with it.

Acid Rain -- The Near Term Challenge

Acid rain, the popular term for acid deposition, is most closely associated with damage to aquatic systems. It may also contribute to forest damage as well as damage to buildings, monuments, and other structures. Acid rain occurs when SO_2 (emitted primarily by coal-fired electric utilities) and NO_x (primarily from transportation sources and utilities) are chemically transformed, transported into the atmosphere, and deposited on the earth in the form of wet or dry deposition. Based on this potential environmental damage, the Bush Administration has recently proposed an aggressive amendment to the Clean Air Act that would control both SO_2 and NO_x from existing electric utility plants. Specifically, the President's proposal calls for:

- A reduction of 10 million tons annually of SO_2 by the end of year 2000 using a base line year of 1980 for tons of SO_2 emitted, primarily from coal-fired power plants.

- A two phase program in order to ensure early reductions. A reduction of 5 million tons is required during Phase 1, by the end of 1995.

- A 2 million ton reduction of NO_x in Phase 2. The plan would also allow utilities to trade reductions of NO_x for reductions of SO_2 or vice versa and thus represents a call for total annual reduction of 12 million tons in acid-rain-causing pollutants.

- A 3-year extension of the Phase 2 deadline for plants adopting "clean coal" repowering technologies combined with regulatory incentives designed to smooth their transition into the marketplace.

- Freedom of choice in cutting pollution. The plan requires all plants of a certain size affected to meet the same emission standard, but does not dictate to plant managers how the standard should be met.

- o Maximum flexibility in obtaining reductions. The plan would allow utilities to trade required reductions so that they would be achieved in the least costly fashion. Full interstate trading would be allowed in Phase 2, although Phase 1 trading would be limited to electric plants within a state or within a utility system.

- o The EPA has estimated the cost of the President's proposal to be $3.8 billion annually in Phase 2 and approximately $700 million per year in Phase 1. This is estimated to represent an increase of over 2 percent by the year 2000 in the nation's $160 billion a year electricity bill.

Dealing with the Likelihood of New Acid Rain Legislation

It appears likely that acid rain legislation with similar provisions to the Administration's proposals will pass the Congress this session. If so, the U. S. electric utility industry will have to make very many cost intensive decisions to comply with provisions of the legislation. For SO_2 control, the industry will have the choice of locating an adequate supply of low sulfur coal or selecting a control technology. The utility will likely look for available low sulfur coal supplies from both the eastern and the western mines to determine the most economical fuel for that particular utility system. The utility will likely compare the coal switching option to the control technology options available. Table 2 describes current and emerging technologies for SO_2 and NO_x control. Included are control technologies available for current pulverized-coal boilers as well as those that could be applied as new boiler technology with inherent SO_2/NO_x control capabilities. The table briefly describes the technology, the estimated level of control of SO_2 and NO_x, and projected commercial availability, including comments primarily related to capability. Note that the overwhelming current choice of U.S. utilities for SO_2 control technology has been lime and limestone wet scrubbers.

EPA's Air and Energy Engineering Research Laboratory (AEERL) has been actively developing acid rain technology capable of low cost retrofit in anticipation of acid rain legislation. Three of the technologies listed in Table 2 have been actively developed by AEERL: LIMB, E-SO_x, and ADVACATE. LIMB technology, which was recently successfully demonstrated at a 100 MW boiler in Ohio, can be a cost effective choice for certain applications. LIMB appears particularly cost effective for older plants burning low to moderate sulfur coal with lower load factors. E-SO_x is another low cost option capable of 50-60 percent SO_2 removal. It is being pilot tested in Ohio. We are particularly excited about the ADVACATE technology which appears to have substantially lower costs than wet scrubbers for almost all retrofit applications. We hope to successfully demonstrate this technology so that it can play a role in cost-effectively controlling SO_2 in the time frame associated with the likely acid rain legislation. Figure 2 describes the major cost elements in terms of dollars per ton of SO_2 removed for LIMB, ADVACATE, and conventional limestone FGD technologies. As you can see, FGD is dominated by capital and labor material costs; whereas LIMB is dominated by sorbent costs. The LIMB process utilizes a typically $70 a ton hydrate material; whereas ADVACATE and FGD utilize lower cost limestone reagent. Note that ADVACATE has an advantage over FGD in all major cost categories allowing it to cost approximately half that of the wet scrubber. Also note that ADVACATE is one

of the few low cost technologies capable of achieving 90 percent SO_2 control.

To elaborate on the choices facing the utility industry, it is worthwhile to summarize the results of a recent study (Emmel and Maibodi, 1989) sponsored by AEERL. The objective of this study was to significantly improve the accuracy of engineering cost estimates used to evaluate the economic effects of retrofitting SO_2 and NO_x controls to the top 200 SO_2-emitting coal-fired utility boilers. This project was conducted in several phases. In Phase 1, detailed, site specific procedures were developed and used to evaluate retrofit costs at 12 actual plants. In Phase 2, simplified procedures were developed to evaluate the site specific costs, and these procedures were used to evaluate retrofit costs at 50 plants. In Phase 3 all remaining 138 plant costs were evaluated. This recently published report presents the cost estimates developed for 576 boilers in 188 plants using the simplified procedures. The study evaluated retrofit costs for the following technologies:

- Limestone FGD
- Additive-enhanced limestone FGD
- Lime spray drying FGD
- Physical coal cleaning
- Coal switching and blending
- Low NO_x combustion
- Furnace sorbent injection with humidification (LIMB)
- Duct spray drying
- Natural gas reburning
- Selective catalytic reduction
- Fluidized-bed combustion or coal gasification retrofit

To generate retrofit costs for each plant, a boiler profile was completed using sources of public information. Additionally, boiler design data were obtained from power plants, data base magazines, and aerial photographs, obtained from state and federal agencies. The plant and boiler profile information is used to develop the input data for the performance and costs models. To enhance the credibility of cost information, which is almost always controversial, the performance and cost results incorporate recommendations from utility companies and a technical advisory group. This group included the utility industry, FGD vendors, and government agency representatives. All the cost estimates were developed using the integrated air pollution control systems (IAPCS) cost model. The IAPCS model was upgraded to include the technologies being evaluated in this program.

The results of this study confirm that costs of various acid rain retrofit options vary considerably from plant to plant. What might be an economical approach at one plant could be prohibitively expensive at another plant due to unique local conditions, such as lack of space or other site-specific factors. Figures 3-6 summarize some of the results of this study. They describe the costs of retrofit control for coal switching, lime/limestone desulfurization, LIMB (for SO_2 control) and three combustion technologies for NO_x control. Figure 3 summarizes the cost per ton of SO_2 removed for coal switching and blending. Price differentials of both $5 and $15 per ton of coal were assumed in this cost analysis since they bracket the likely differential for many existing boilers in the Eastern U.S. Note that, for about 50 percent of the applicable

boilers for a $5 price differential, the levelized cost of control will be substantially less than $1,000 per ton of sulfur removed. (All costs were calculated on a levelized basis; i.e., they were increased over first year costs to take into account likely inflation over the control's lifetime.) However, for boilers already burning relatively low-S coal, even this relatively small coal price differential can yield substantially higher cost of controls per ton of sulfur removed. For the higher priced differential, typically for plants far from available low sulfur coal, only 25 percent of the boilers can be controlled at less than $1,000 per ton. Utilities will likely look very closely at the low sulfur coal option which in many cases will likely be the least expensive option.

Figure 4 summarizes the cost per ton of SO_2 removed for lime or limestone FGD technology. As shown, certain plants can be controlled for less than $1,000 a ton; but, for about 75 percent of the plants, costs will be higher than that. For the most expensive 25 percent of boilers, costs will be quite high due primarily to difficulty of retrofit.

Figure 5 summarizes the cost per ton of SO_2 removal for LIMB technology. Two cases are studied corresponding to 50 or 70 percent SO_2 removal from the LIMB/humidification technology. For most cases, this technology is less expensive per ton of SO_2 removed, especially if 70 percent SO_2 removal is achievable for a given plant.

The last figure in this series, Figure 6, summarizes costs per ton of NO_x removed utilizing three low NO_x combustion technologies: low NO_x burners (LNB), natural gas reburning (NGR), and overfire air (OFA), another combustion modification technology. As shown, the combustion technologies LNB and OFA are considerably less expensive than natural gas reburning. However, for certain classes of boilers, such as cyclones, reburning may be the only feasible option. Also note that 75 percent of the boilers can be controlled with a low NO_x burner or overfire air system for costs below $500 per ton of NO_x removed.

Results of this study should be useful to utilities, states, and others who will likely be making or monitoring the difficult choices of control mandated by the expected acid rain legislation.

In January 1990, the authors of the retrofit study (Emmel and Maibodi) were asked to apply the results of this study to a hypothetical 10 million ton per year SO_2 reduction program (from 1980 emission levels). The objective was to estimate the maximum potential benefit of emerging technologies (i.e., LIMB and ADVACATE) to an acid rain retrofit program.

The methodology involved selecting the lowest cost option for a particular plant, ultimately achieving the required 10 ton reduction by retrofitting the top 200 SO_2-emitting plants. For this analysis, the following limited sets of available control options were assumed:

Cases 1 & 2	Cases 3 & 4
Coal Switching/Blending	Coal Switching/Blending
Limestone FGD	Limestone FGD

LIMB (50% removal)

LIMB (50% removal)
ADVACATE (limestone, 90% removal)

Cases 1 and 3 assumed a low sulfur coal incremental cost of $5/ton; whereas, Cases 2 and 4 assumed a $15/ton differential. Cases 3 and 4 included the ADVACATE process to estimate the impact of such a technology assuming costs half those of wet FGD and retrofittability similar to that of wet FGD. Note that this is not a demonstrated technology; cost savings should only be considered an upper limit of what might be achievable if successfully demonstrated and freely selected by the utility industry, despite lack of extensive field operation experience.

Figure 7 shows the results of this analysis. For Cases 1 and 2, coal switching, FGD, and LIMB would all play major roles, with coal switching particularly important at the low ($5 per ton) coal price differential (Case 1). For Cases 3 and 4, ADVACATE would play the major role, essentially displacing all other options for the high ($15 per ton) coal price differential (Case 4). Maximum possible annual cost savings associated with ADVACATE technology availability are in the order of $2 billion.

Global Warming -- The Longer Term Utility Challenge

The most important long-term challenge relative to environmental protection for the electric utility industry appears to relate to global warming. As has been publicized extensively in recent months, there is concern for major global warming projected to occur in the early-to-mid-21st century. Although the sources of gases that contribute to global warming are ubiquitous, electric utilities represent one of the more important of these sources. Of course, all fossil fuels generate CO_2 during combustion. However, coal is a particularly bad actor since it generates about 220 lbs of CO_2 per million BTU, compared to half that amount for natural gas and about two-thirds that amount for oil. Figure 8 (Lashoff and Tirpak, 1989) illustrates that the global warming problem is clearly an international one, and projects that the U.S. currently represents about 20 percent of the problem. The Soviet Union, Europe, China, Brazil, and India are also major contributors. Figure 9 [Smith (IEA), 1988; Smith and Tirpak, 1989; Mintzer, 1987; Ramanathan et al., 1985; Lashof and Tirpak, 1989] illustrates that, although CO_2 is the major global warming trace gas, chlorofluorocarbons (CFCs), methane, nitrous oxides, and other anthropogenic gases contribute significantly to the anticipated global warming. This figure also estimates the relative importance of the various global sources which contribute to global warming in the 2030 time frame. The utility industry is clearly a major source. Also important are other anthropogenic activities including: industrial, transportation, and residential combustion; and industrial non-combustion activities (which generate CFC emissions). Other sources include: deforestation which generates CO_2, and livestock production, agriculture, biomass burning, and other sources that generate methane to the atmosphere.

If the international community is to seriously deal with this problem, the electric utility industry may be among those sources that are targeted to avoid the possibility of unacceptable global warming.

Discussed briefly here are some of the more obvious approaches that could be utilized by the utility industry between now and 2020 in attempting to decrease CO_2 emissions.

Later this paper will attempt to quantify the effectiveness of these options using a simple emission allocation model. The most straightforward approach is user conservation. By decreasing the demand for electricity or, more accurately, by decreasing the growth in demand over historical patterns, major reductions over "business as usual" can be realized.

Another option is to utilize nuclear power to offset emissions from fossil fuel units. However, the prospects for further capacity additions are uncertain. According to DOE, "No additional orders for nuclear powerplants are likely in this country until the conditions of the past few years are changed" (U.S. DOE, 1987). The primary reasons for this bleak outlook are concern over safety, waste disposal, nuclear proliferation, and high capital costs. Several of these concerns may be mitigated with some of the advanced nuclear fission designs. One of the promising technologies is the modular high temperature gas reactor (HTGR). This technology is compartmentized and is immune to the uncontrollable runaway reaction potential of conventional technology. The HTGR concept has not yet been demonstrated. Current estimates are that the technology could be made commercially available in 1995. With an implementation time of 9 years, power generation using HTGR could begin in 2004.

Unfortunately, nuclear fusion, which utilizes water as the nuclear fuel and potentially avoids the safety and waste problems of nuclear fission, is not likely to be commercially available before 2020.

A third option would be wide-scale application of solar electric technologies, again displacing fossil fuel emissions. There are two general methods for producing electricity from sunlight: photovoltaics (PV) and solar thermal systems. Estimates of the potential contributions to the nation's future electrical energy requirements from these two technologies have large uncertainties. For either of these methods to be commercially significant for power generation, major improvements must be made in the area of capital cost, electricity storage, and conversion efficiency. Currently, such systems are generally not competitive with coal-fired power plants, although costs have been decreasing in recent years.

The use of biomass electrical generating capacity also presents a potentially attractive approach. By burning biomass, it is possible to generate electricity without any net emissions of CO_2 to the atmosphere. This is accomplished by utilizing photosynthesis for atmospheric removal via fixation of the same quantity of CO_2 generated during the combustion process. Potential fuel sources include forest wood, unused wood residues, crop residues, herbaceous energy crops, livestock and poultry wastes, and municipal solid wastes.

Forest wood energy research is focusing on biotechnological engineering for yield improvement and stress resistance. Research on methods for efficient biomass processing are encouraging. Cofiring with various combinations of woody biomass, non-hazardous solid waste, herbaceous biomass, coal, and natural gas are also promising and are currently implemented commercially on small scale.

Another option that has been touted by some would be to develop and ultimately implement so-called clean coal technology. This technology could include integrated

coal gasification combined cycle (IGCC) processes, as well as pressurized fluidized-bed combustion. Table 2 describes these processes. The objective is to generate electricity from coal at higher efficiency, thereby decreasing CO_2 emissions. For IGCC, the primary reason for integrating the gasification system with the combined-cycle plant is that this design configuration substantially improves the overall system energy efficiency or heat rate. Although all components (i.e., gasifiers, gas coolers, acid gas removal systems, combined cycles) included in an IGCC configuration have been demonstrated to operate at full commercial scale, they have only recently been operated in unison in a complete system to generate electric power. Integrated control and operation of such plants in a commercial environment must be demonstrated on a large scale before the electric utility industry will seriously consider adopting IGCC systems for electric power generation. Since this technology is still under development, probably it will be unavailable for commercial application before 1996. Assuming a 7-year implementation time for the technology, the first units could not begin electrical production before 2003.

Another potentially promising option is to substitute natural gas for coal which results in lower CO_2 emissions due to the higher hydrogen to carbon ratio of natural gas. Consequently, using natural gas as fuel in conventional boilers for electric power production would substantially decrease emissions of CO_2. Also, natural gas firing of utility boilers could begin almost immediately since existing coal-fired boilers can be easily retrofitted to burn gas. The primary limitations to use of this resource are fuel cost and limited availability. In 1985, gas consumption by U.S. utilities was about 3.2 quads. Total natural gas consumption in 1985 was 17.0 quads. U.S. reserves are estimated to last about 70 years at that rate of consumption.

In order to estimate the impact of some of these options on utility industry generation of CO_2, I have developed a simple emission allocation model which I call the utility CO_2 emission model (UCEM). This model assumes a certain annual growth rate in electrical demand. It also estimates retirement of existing capacity by retiring units once they reach an assumed retirement age. It then fulfills new and replacement demand by adding capacity via one or more combinations of new technologies whose capacity are input into the model. The UCEM utilizes all the assumed new technology, and then allocates any remaining needed capacity via conventional pulverized coal technology.

Table 3 describes the 10 options evaluated and the input data for the projected penetration of these technologies/approaches from the year 2000 to the year 2020. Note that of these 10 options, only the base case (1) assumes a "conventional wisdom" annual electric growth rate of 2.5 percent. This base case assumes all new and replacement capacity will be conventional pulverized coal generators. All the other options assume user conservation based on a 1.5 percent growth rate. Also note the assumed conversion efficiency for the technologies. This is important since higher efficiencies lead to lower CO_2 emissions for a given electrical output. The megawatt penetration I have assumed for nuclear, solar, biomass, clean coal, and the amount of natural gas that may be available in quads to meet this expected increase in electrical demand are based on my judgment as to what might be reasonable upper limits to such penetration in this time frame. Clearly, opinions of persons knowledgeable in this field will differ on what are reasonable technology penetration predictions.

Figures 10 through 13 summarize the results of this model analysis for 10 options. Figure 10 projects CO_2 emissions for the base, conservation, nuclear (plus conservation), and new gas (plus conservation) options. As you can see, conservation is effective with gas (plus conservation), adding a significant near term benefit with nuclear (plus conservation) providing some longer term benefit assuming, of course, the penetration assumptions listed in Table 3.

Figure 11 compares the same base case and conservation options with a clean coal (plus conservation) scenario. As you can see, the clean coal approach offers only a modest advantage over conservation alone. This is because clean coal technologies are still major contributors of CO_2 since their higher efficiency only modestly mitigates CO_2 reductions compared to conventional coal units. This approach will probably have only a marginal benefit over the next 30 years.

Figure 12 compares the base and conservation options with the solar (plus conservation) and biomass (plus conservation) options. Again, some significant but modest improvements over conservation alone are realized. Of course, higher utilization of these technologies could allow these technologies to make a more significant impact.

The last figure in this series, Figure 13, compares the same two base and conservation options with two combination options. The renewable option shows the effect of biomass and solar penetration, whereas the so-called maximum technology plus gas option shows the effect of all of these technologies plus natural gas applied in tandem. As you can see, only this option (of those evaluated) yields stabilization of CO_2 emissions in this time period. I could come up with no credible combination that would show a major decrease of emissions from current levels. Only more drastic conservation measures appear to allow for such a possibility.

Figures 14 through 17 present additional model outputs for two of the options. Figures 14 and 15 show electric and CO_2 generation by source, respectively, for the maximum technology plus gas option (Option 10) that allows a possible approach to stabilizing CO_2 emissions. Similarly, Figures 16 and 17 present electrical production and CO_2 projections by source, respectively, for the clean coal option.

Since conservation appears such an important component of any electric utility CO_2 stabilization program, it is informative to look at historical patterns of electrical production. Figure 18 shows the historical pattern of annual electric growth rate in the United States from 1935 to 1988. For the period 1935 through 1985, the bars represent averages for the preceding 5 years, while for the period 1985 through 1988, bars represent single-year growth rates. As you can see, historical growth rates, except for the depression impacted 1930-1935 and the recession impacted 1986 time frames, have never been below 3 percent. Most experts project a 2.5 percent annual growth rate between now and the early 21st century (DOE, 1987). Therefore, my conservation options (Table 3), assuming only 1.5 percent growth rate, clearly suggest that fundamental changes will have to be made, most likely in the way we price energy if we are serious about decreasing growth rate substantially below historical levels.

Conclusions

The utility industry will likely face two major waves of environmental challenges in the next 20 years. The first is associated with the requirement to limit emissions of both SO_2 and NO_x from existing coal-fired boilers. It appears likely that acid rain legislation mandating such a program will pass the U. S. Congress during 1990. Utilities will likely be able to select the most cost-efficient option from available alternatives: coal switching, wet FGD, and such emerging technologies as LIMB and possibly ADVACATE.

The longer term and more formidable challenge is associated with concern over potential global warming, to which utility power generation is an important contributor. Dealing with this problem will require fundamental changes in how we both use and generate electricity. Only by combining end use conservation and massive quantities of non-fossil fuel generating capacity can CO_2 emissions be stabilized.

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Table 1. Important Electrical Power Plant Pollutants

Pollutant	Health Concern	Environmental Concern	Coal Role
Sulfur Dioxide	- Respiratory tract problems. - Permanent harm to lung tissue.	- Acid deposition damage to lakes, streams, and forests. - Visibility.	Coal combustion is dominant source.
Nitrogen Oxides	- Respiratory illness and lung damage.	- Acid deposition. - Increased ozone: forest damage.	Coal combustion and autos are major sources.
Airborne Particulates	- Eye and throat irritation, bronchitis, lung damage.	- Visibility.	Power plants have diminished in importance.
Carbon Dioxide	- Major impacts of global climate warming. - Indirect health impacts unknown.	- Destruction of sensitive eco-systems by global warming. - Increased air pollution.	Coal most important fuel due to large use and high carbon/hydrogen ratio.

Table 2: SO_2 and NO_x Control Technologies for Coal-Fired Boilers

Technology	Description	Control, %* SO_2	Control, %* NO_x	Estimated Commercial** Availability	Comments
Wet flue gas desulfurization (FGD)	Limestone or lime in water removes SO_2 in a scrubber vessel. Additives may be used to enhance SO_2 removal. A wet waste or gypsum is produced.	70-97	0	Current for new boilers and retrofit.	State-of-the-art for higher S coal and FGD. Certain retrofits difficult.
Dry FGD	Lime in water removes SO_2 in a spray dryer, which evaporates the water prior to the vessel exit. Produces a dry waste.	70-95	0	Current for low to moderate S coal for new boilers. High S coal retrofit, 5 yrs.	Demonstration for high S coal retrofit is necessary, but may be limited to 90% SO_2 removal.
E-SO_x/in-duct injection	Lime and water are injected in a boiler duct and/or ESP (E-SO_x) and react with SO_2 similar to a spray dryer.	50-70	0	Pilot scale only. Demonstrations required, 3-7 yrs.	Potentially low cost retrofits. May be site-specific limits.
Limestone injection multistage burners (LIMB)	Low NO_x burners and upper furnace sorbent injection. May use humodification to improve SO_2 capture and ESP performance.	50-70	40-60	Wall, current; T-fired, 3-4 yrs.	T-fired wall-fired demo complete. Applicable to $\leq$3% S coal retrofits.

(Continued)

Table 2: Sulfur and Nitrogen Oxide Control Technologies for Coal-Fired Boilers (Continued)

Technology	Description	Control, %* SO_2	Control, %* NO_x	Estimated Commercial** Availability	Comments
Advanced silicate (ADVACATE)	Several variations. Most attractive: adding limestone to boiler, generating lime. Lime/flyash collected in cylone and reacted to generate highly reactive silicate sorbent. Moist sorbent added to downstream duct.	Up to 90	0	Pilot scale only. Demo required, 3-7 yrs.	Most promising emerging retrofit technology. Capable of 90% removal with costs 50% of wet scrubber.
Low NO_x burners, overfire air modifications	Burner/boiler design controls coal/air mixing to reduce NO_x formation.	0	40-60	Now, new boilers and retrofit.	Additional retrofit demos desirable.
Natural gas reburning	Boiler fired with 80-90% coal. Remaining fuel (natural gas) is injected higher in boiler to reduce NO_x. Air added to complete burnout. Sorbent may be injected to capture SO_2.	Without sorbent, 10-20; with sorbent 50-60	50-85	Demos starting, available in 3 yrs.	May be only combustion NO_x control for cyclones. Sensitive to natural gas price. New or retrofit.

(Continued)

Table 2: Sulfur and Nitrogen Oxide Control Technologies for Coal-Fired Boilers (Continued)

Technology	Description	Control, %* SO_2	Control, %* NO_x	Estimated Commercial** Availability	Comments
Selective catalytic reduction (SCR)	Reacts NO with NH_3 over a catalyst at 500-700°F (260-370°C).	0	80-90	Pilot plant only in U.S., 4 yrs.	Catalyst cost and life main issues. Retrofit or new, if demos in U.S.
		<u>SO_2/NO_x New Boiler Systems</u>			
Atmospheric fluidized-bed combustion (AFBC)	Coal and air are burned in fluidized bed of sorbent which captures SO_2 and limits NO_x formation.	70-90	50-70	Now, for industrial boilers. Utility demo in progress (2-3 yrs.).	Primarily for new boilers. Repowering (retrofit) applicability limited.
Pressurized fluidized-bed combined cycle (PFBCC)	Coal burned in a fluidized bed at elevated pressure. Gas cleaned and run through gas turbine which generates electricity. Waste heat converted to steam to generate electricity.	90-95	70-80	Pilot plant data. DOE demo initiated, 5-10 yrs.	Primarily for new boilers. Repowering involves replacing virtually all existing plant equipment.

(Continued)

Table 2: Sulfur and Nitrogen Oxide Control Technologies for Coal-Fired Boilers (Continued)

Technology	Description	Control, %* SO_2	Control, %* NO_x	Estimated Commercial** Availability	Comments
Integrated gasification combined cycle (IGCC)	Gasifier converts coal/air to fuel gas, sulfur removed, and fuel gas burned in a combustion turbine. Waste heat used to generate steam. Electricity generated by both combustion and steam turbines.	95-99	40-95	Cool water demo conducted, economics questionable. Two DOE demos initiated, 5-10 yrs.	See PFBCC comments. Also, economic operation depends on hot fuel gas cleanup and high temperature turbines which are not demonstrated.

*Control efficiency is % reduction from emission levels for uncontrolled coal-fired power plants.
**Estimated commercialization for some technologies is strongly dependent on successful demonstrations.

Table 3: Ten scenarios analyzed by Utility CO_2 Emission Model (UCEM).

Option Abbrev.	Option No.	Option	Assumed Penetration All in MWe, Except No. 9: quads					Conv. Eff.	Annual Electric Growth Rate, %
			2000	2005	2010	2015	2020		
Base	1	Base Case - No New Technology						0.36	2.5
Conserv.	2	Conservation - No New Technology						0.36	1.5
Nuclear	3	Nuclear (& Conservation)	0	10,000	20,000	40,000	80,000	0.33	1.5
Solar	4	Solar (& Conservation)	0	5,000	10,000	20,000	40,000	----	1.5
Biomass	5	Biomass (& Conservation)	0	5,000	15,000	30,000	60,000	----	1.5
Clean Coal	6	Clean Coal (& Conservation)		10,000	40,000	80,000	100,000	0.42	1.5
Renewable	7	Solar + Biomass + Conservation (Renewable Option)	See Solar (4) and Biomass (5) Above						1.5
Max. Tech	8	Option 7 + Nuclear	See Solar, Biomass, and Nuclear (3) Above						1.5
New Gas	9	Gas (& Conservation)	4.0	6.0	7.0	7.0	7.0	0.40	1.5
Max. Tech & Gas	10	Option 8 + Gas (9)	See Solar, Biomass, Nuclear, and Gas (9) Above					----	1.5

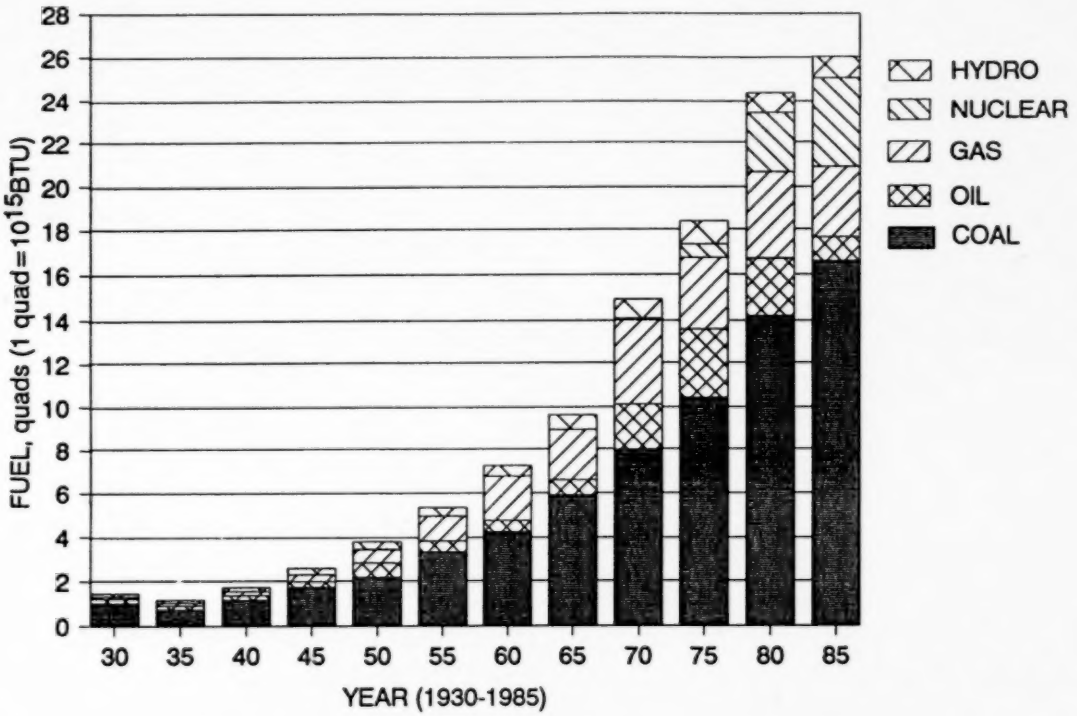

Figure 1. U.S. electrical production history by fuel, 1930-1985.

COAL S=2.5%, 250 MWe, LOAD FACTOR=0.6, INFLATION 8%

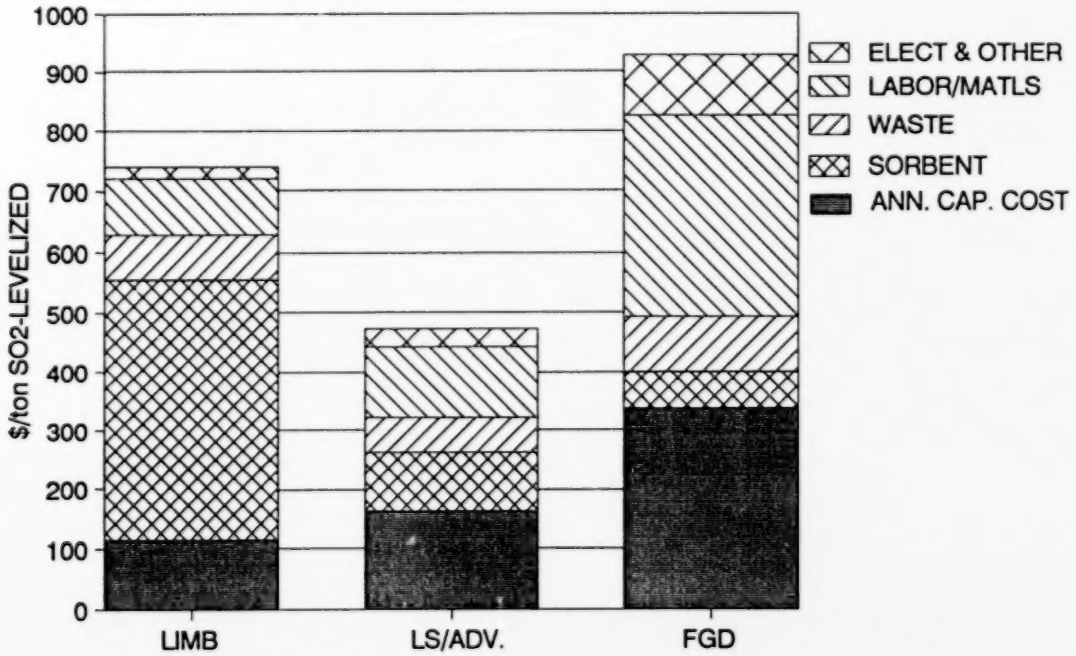

Figure 2. Relative cost of LIMB, limestone ADVACATE, and FGD processes.

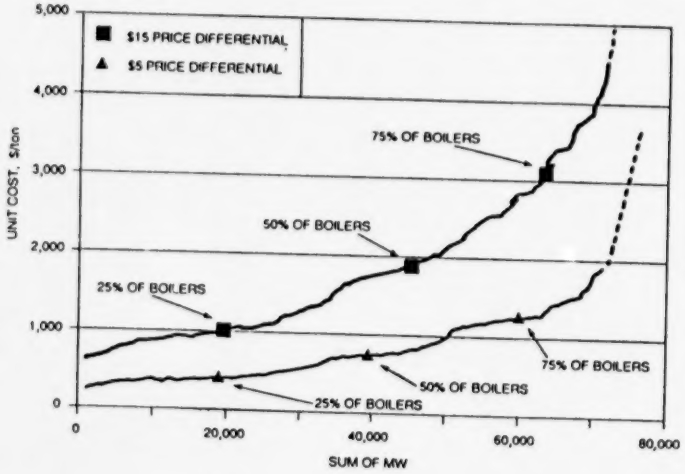

Figure 3. Summary of cost per ton of SO_2 removed results for coal switching and blending.

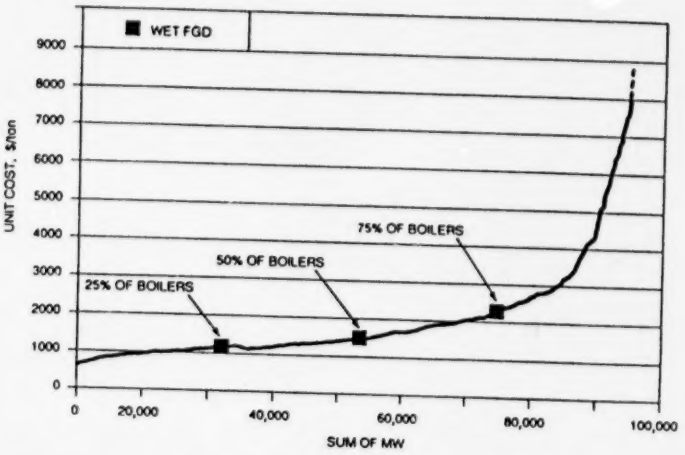

Figure 4. Summary of cost per ton of SO_2 removed results for lime/limestone flue gas desulfurization.

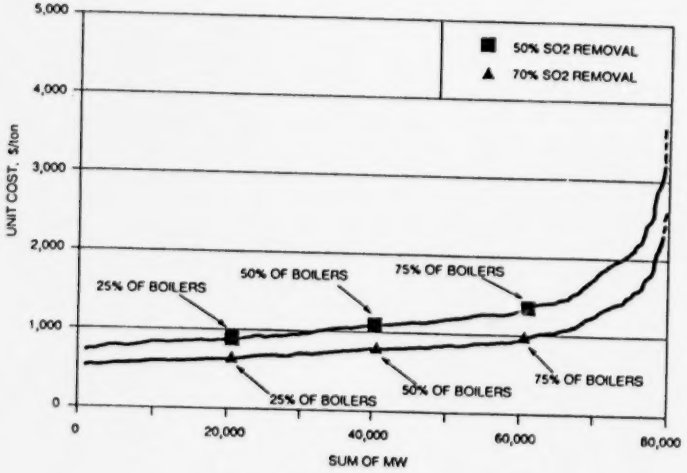

Figure 5. Summary of cost per ton of SO_2 removed for furnace sorbent injection (LIMB).

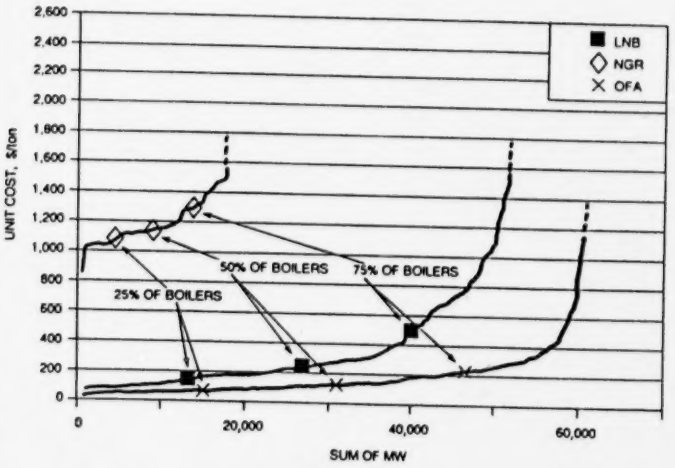

Figure 6. Summary of cost per ton of NO_x removed for low NO_x combustion.

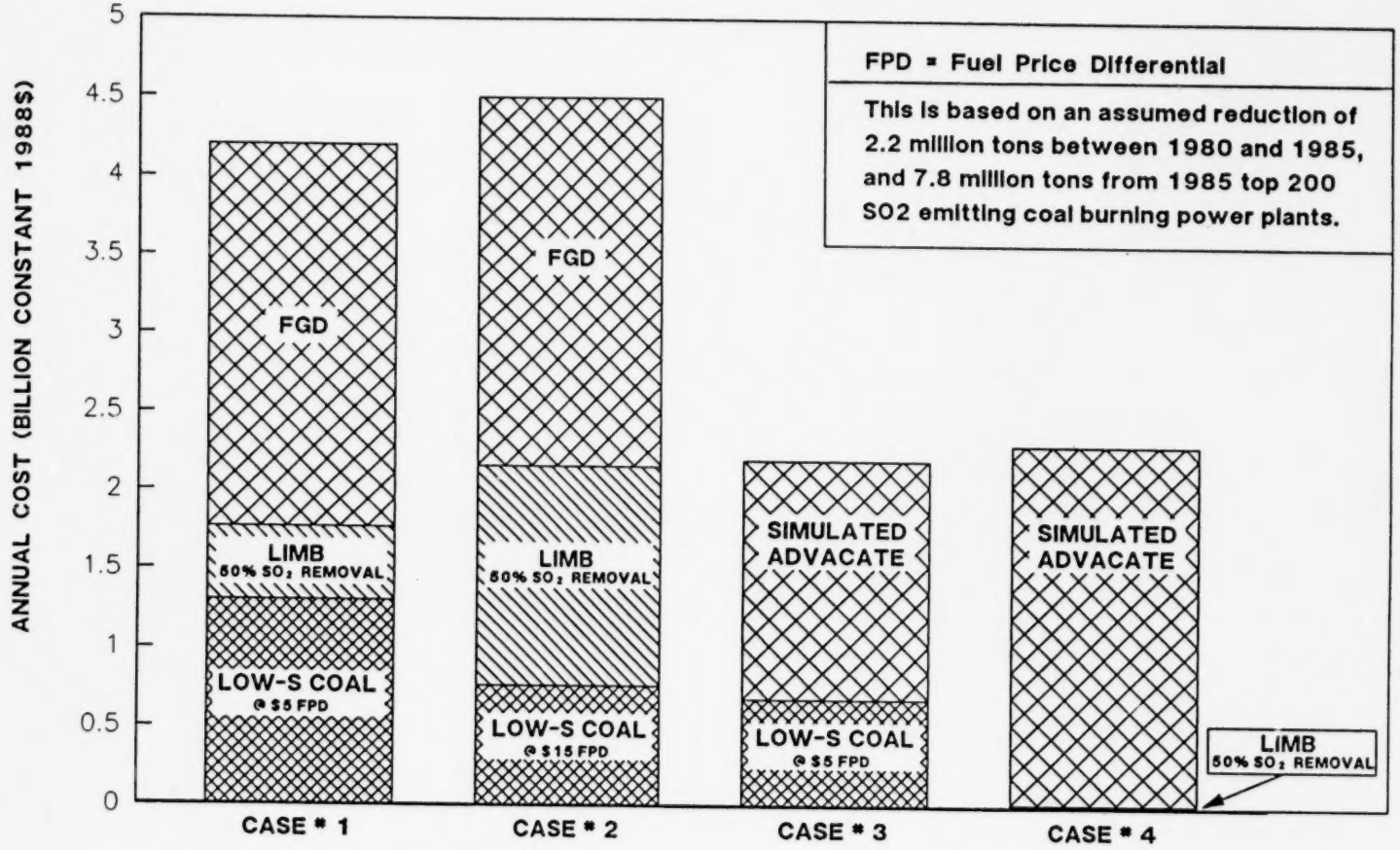

Figure 7. Annual cost of achieving a 10 million ton reduction of SO2 per year from 1980 emission levels in the eastern region of the United States.

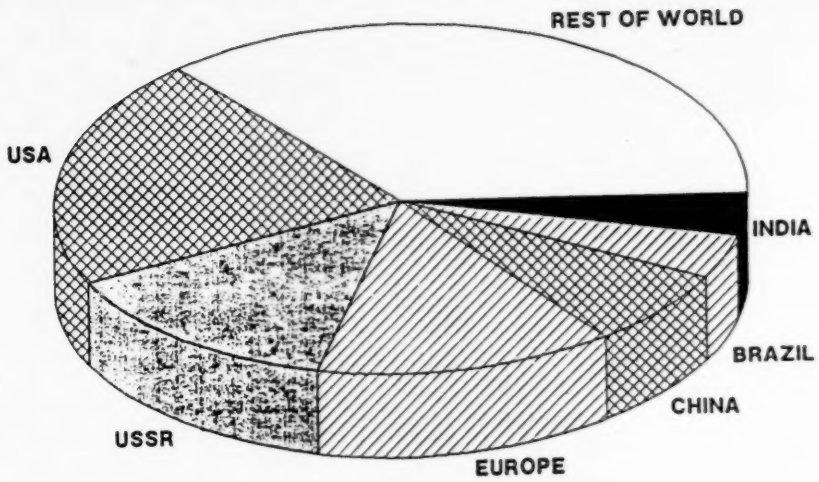

Figure 8. Projected regional contributions to global warming.

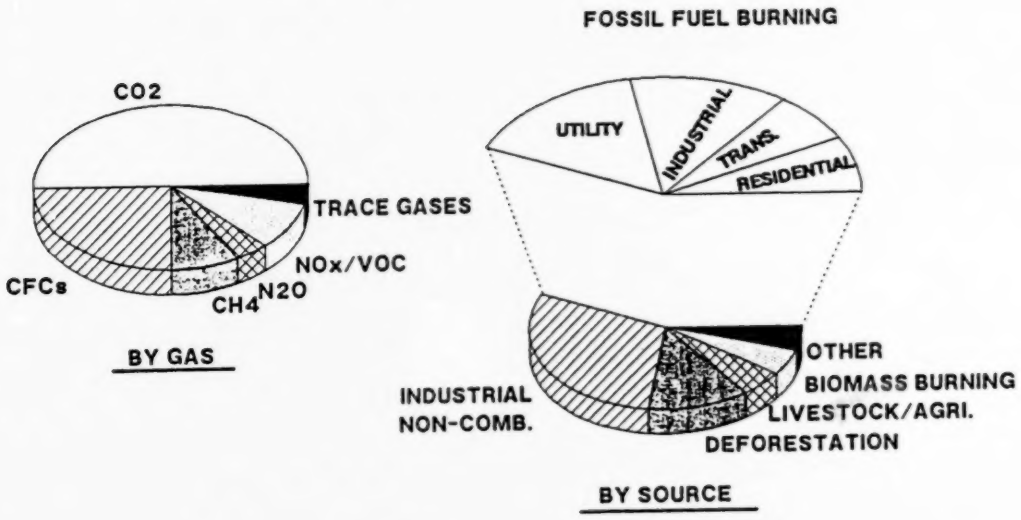

Figure 9. Projected contributions to global warming in 2030 by gas and source.

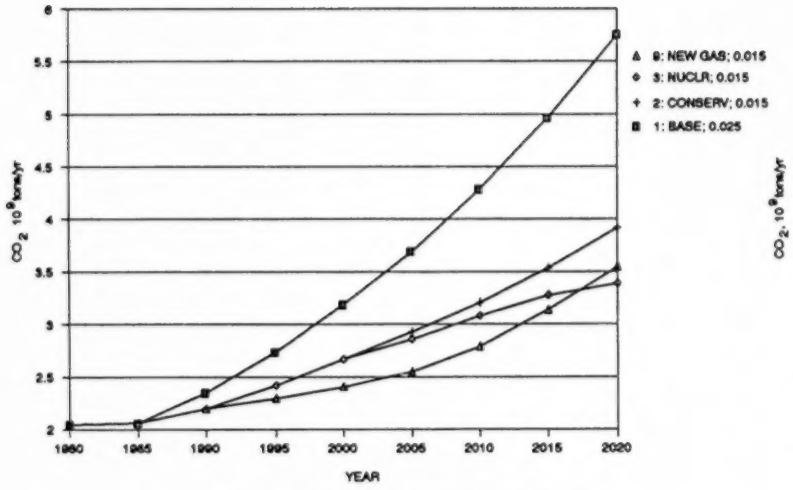

Figure 10. Projected utility CO_2 emissions for base, conservation, nuclear, and new gas options.

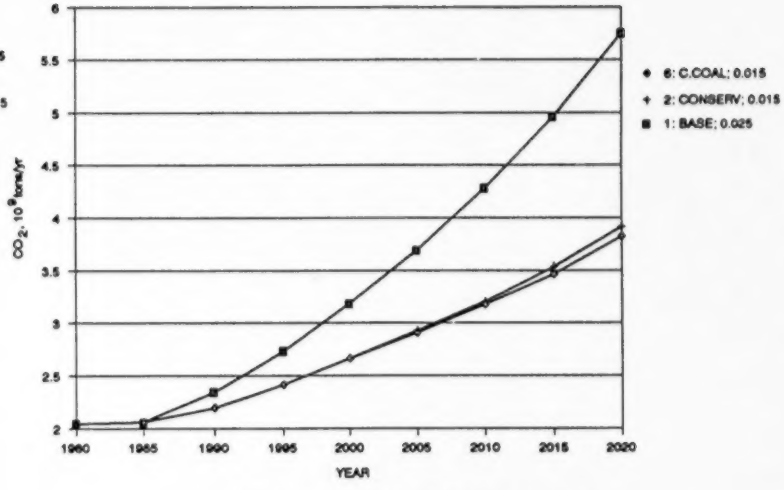

Figure 11. Projected utility CO_2 emissions for base, conservation, and clean coal options.

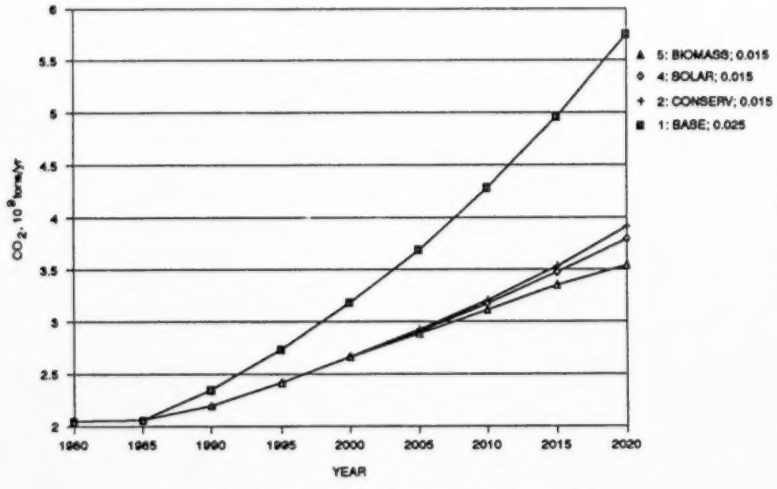

Figure 12. Projected utility CO_2 emissions for base, conservation, solar, and biomass options.

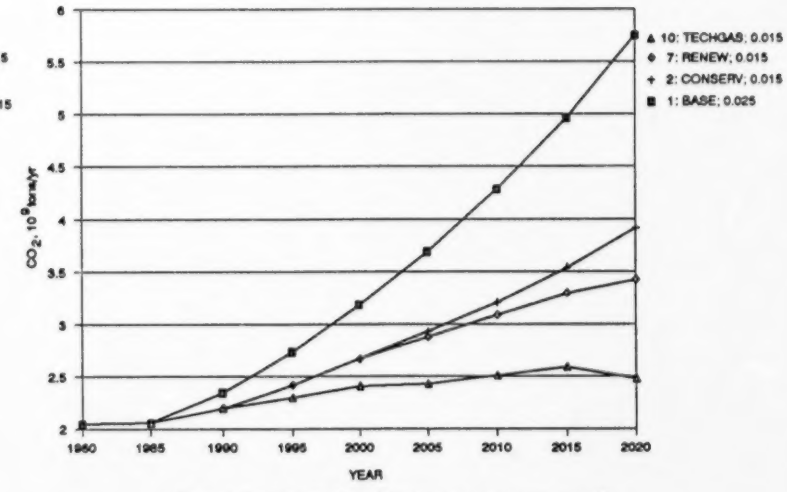

Figure 13. Projected utility CO_2 emissions for base, conservation, renewable, and technology + gas options.

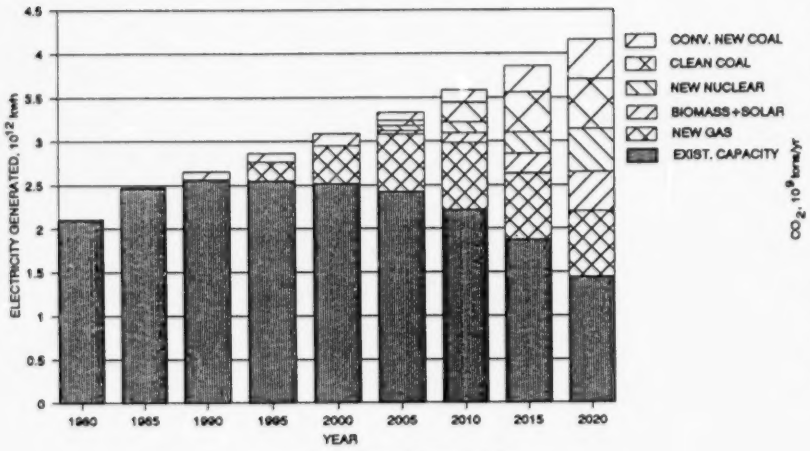

Figure 14. Electric generation by fuel/technology - max. technology + new gas option.

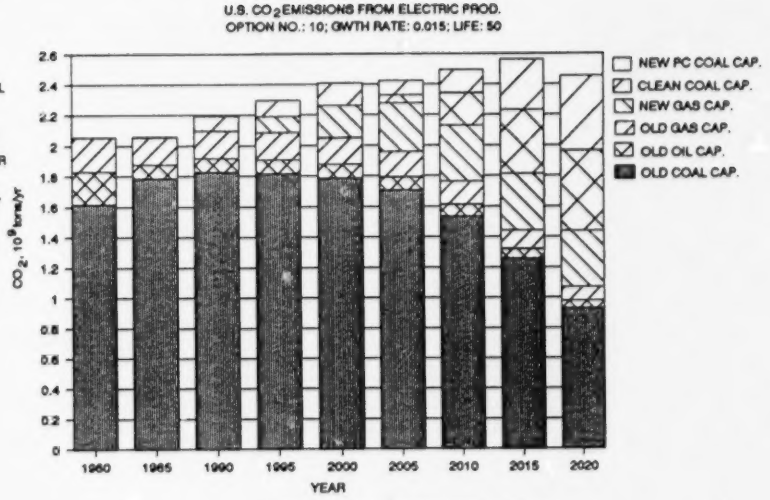

Figure 15. U.S. CO_2 emissions for max. technology + new gas option.

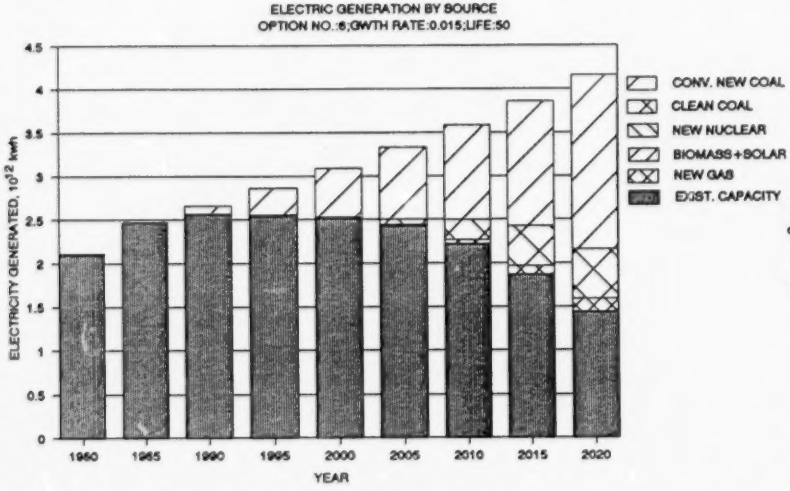

Figure 16. Electric generation by fuel/technology - clean coal option.

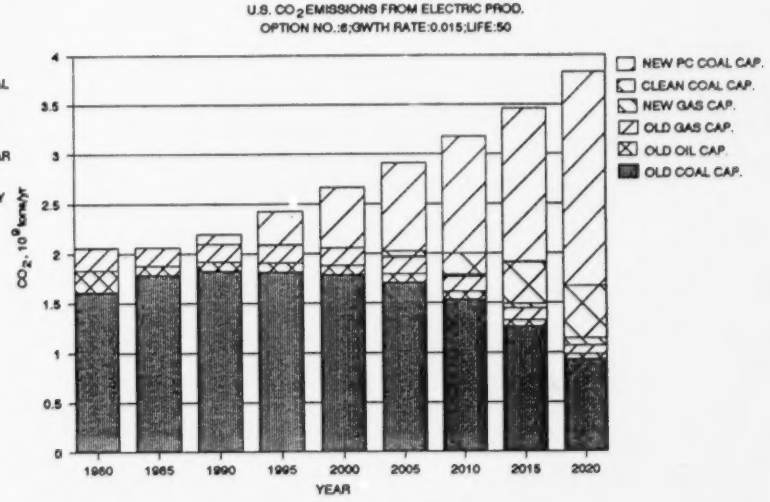

Figure 17. U.S. CO_2 emissions for clean coal option.

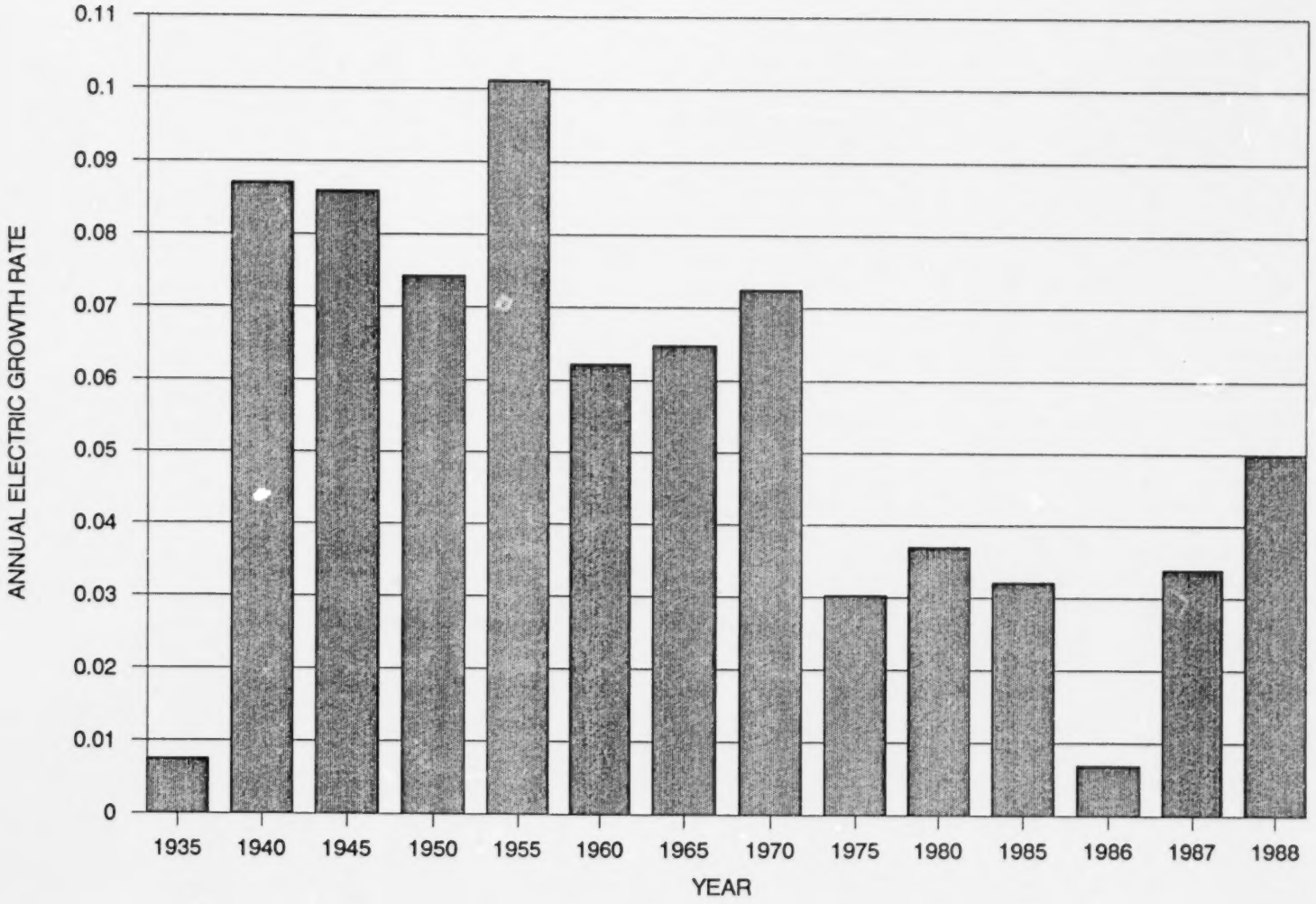

Figure 18. U.S. annual electric growth rate, 1935-1988.